

SHEMS DUNKIEL RAUBVOGEL & SAUNDERS PLLC

REBECCA E. BOUCHER*
BRIAN S. DUNKIEL**
EILEEN I. ELLIOTT
GEOFFREY H. HAND

ANDREW N. RAUBVOGEL
MARK A. SAUNDERS
RONALD A. SHEMS*
KAREN L. TYLER

July 2, 2009

Susan M. Hudson, Clerk
Vermont Public Service Board
112 State Street – Drawer 20
Montpelier, VT 05620-2701

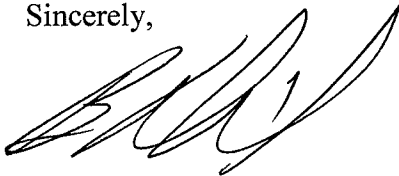
Re: Docket No. 7523
Implementation of Standard Offer Prices for Sustainably Priced Energy
Enterprise Development ("SPEED") Resources

Dear Ms. Hudson:

Enclosed for filing please find Renewable Energy Vermont's initial response to questions presented by the Board's Memorandum of June 22, 2009 issued in connection with the above-referenced docket, and the Board's list of issues circulated at the June 19, 2009 workshop, as revised on June 26, 2009.

Renewable Energy Vermont appreciates the opportunity to submit these comments for the Board's consideration.

Sincerely,



Brian Dunkiel
Andrew Raubvogel
SHEMS DUNKIEL RAUBVOGEL & SAUNDERS PLLC
Attorneys for Renewable Energy Vermont

cc: Service List (via email)



July 2, 2009

Renewable Energy Vermont (REV) would like to submit the following preliminary comments in response to the Public Service Board's (PSB) June 26, 2009 memo.

In the June 26th memo, the Board has identified four objectives that it believes it must accomplish by September 15, 2009 to meet its statutory mandate:

- Review statutory interim prices
- Determine project eligibility
- Establish a queuing process
- Develop standard offer contract terms

The Board has requested comments by July 2, 2009 concerning many issues relating to its four above-stated objectives. REV does not provide comment on all the issues but does focus on the four issues outlined as priorities in the June 26th memo. REV understands that the Board's order implementing the statute needs to resolve numerous complicated policy questions while adhering to the statute's requirements. With this in mind, when resolving policy questions contained in REV's comments, REV has and encourages the Board to also follow the following principles:

1. Policy questions should be resolved in a manner that on balance will achieve the statute's objective to encourage the "rapid development and commissioning" of plants, and
2. The Order should implement a program that is simple, clear and reliable.

1. Cost Issues

- *Where should the Board obtain cost data – publicly available information, prior Board dockets, by mandating disclosures from developers or vendors? If the Board mandates disclosures, how should it deal with confidentiality issues?*

Cost Data

REV recommends that the Board retain experts to inform and opine on the reasonableness of the prices contained in H.466 as enacted.

More specifically, REV recommends that the Board explore retaining experts at the national laboratories, such as the Lawrence Berkeley National Laboratory and the National Renewable Energy Laboratory, who have been involved with tracking cost trends for different technologies, and are willing and able to assist Vermont with setting up its standard offer program.

REV can supply the Board with cost and feed-in tariff price information from other jurisdictions that have already dealt with similar policy decisions (both nationally and internationally). Figures from other jurisdictions can vary significantly based on local factors such as renewable energy resources, policy incentives and goals, and cost drivers. However, such information does provide a general benchmark for the Vermont program.

Confidentiality

It is REV's position that it would be inconsistent with Board precedent to require merchant facility developers to disclose proprietary cost or operating information for specific projects because as with other merchant facilities, the risk of project failure due to economic infeasibility for a project in the SPEED program is still carried by the project developer. *See e.g.*, Order Re: KCG Motions to Compel, Petition of EMDC, LLC, Docket No. 6911 (7/15/2005). Maintaining confidentiality of proprietary cost and operating information of merchant facilities is also consistent with the statutory changes to the SPEED program exempting from 30 V.S.A. §248(b)(2) projects not "financed directly or indirectly through investments, other than power contracts, backed by Vermont electricity ratepayers." 30 V.S.A. §8005(b)(8).

- *At what level of granularity should the Board consider costs? By resource? By other characteristics? Should it set different prices for different sized projects? If so, what are the proper thresholds?*

REV recommends that different prices should be set for different technologies and different sizes of plants, and will help to identify data that will support such prices.

As an example, REV has included a table in Appendix A that includes a comparison of how jurisdictions in the US¹ and abroad have differentiated renewable energy price thresholds by size in existing and proposed feed-in tariffs ("FIT(s)").² Given the project-

¹ It should be noted that several states, including Indiana, Illinois, Michigan, Minnesota, New York, Rhode Island, and Washington State have introduced similar legislative bills during the last two years. Collectively, these types of feed-in tariffs are referred to as "the Michigan model" since Michigan was the first state to introduce such a bill.

² The term "standard offer" is used as the label for the program in the legislation. The standard offer program, however, can also be characterized as a type of "feed-in tariff," or FIT, and the two terms will be used interchangeably in this document.

based cap of 2.2 MW, REV recommends that costs be differentiated primarily by project size, rather than by comparative availability of renewable resource.³

For the purposes of future discussion, REV offers the following illustrative thresholds for differentiating standard offer contract prices by project capacity:

Resource	Wind	Biogas	Photovoltaics
Tier 1	< 15 kW	< 50 kW	<15 kW
Tier 2	15 – 150 kW	50 kW – 150 kW	15 – 150 kW
Tier 3	151-500 kW	> 150 kW	151 – 500 kW
Tier 4	> 500 kW		> 500 kW

- *What tax credit, grant or other incentive programs (excluding RECS) are available to renewable generators and how should the Board value them? Should it set different prices for plants that are vs. plants that are not eligible for credits, grants or other incentives?*

REV can provide an inventory of tax credit, grant, or other incentive program available to renewable generators at the Board's request.

REV recommends that the issue of whether or not to include other federal or state incentives in the price calculations be resolved in a way that best supports rapid development and commissioning of renewable resources.

There is a range of different state and Federal tax benefits and incentives available to renewable generation facilities in Vermont, depending on such factors as facility size and ownership structure. At the Federal level, these benefits include a production tax credit, investment tax credit, cash grant in lieu of the investment tax credit⁴ and accelerated depreciation. All of these incentives, with the exception of the cash grant, require a Federal tax liability to realize the full value of the incentive.

Under most existing and proposed feed-in tariffs, additional available incentives are taken into account when setting the price. Key questions include whether to assume that generators can claim all available incentives when setting the rate, that only a subset of incentives should be calculated, or that generators should be allowed to designate which incentives they plan to employ. Another key concern is whether to differentiate between taxable and non-taxable entities (discussed in the subsequent response). It is in the

³ Generally, the only renewable technology that has been price differentiated according to resource availability under feed-in tariffs is wind. In the US, the bills based on the Michigan model have proposed differentiating wind generators by output per square meter of swept area per year, whereas European countries (e.g. France, Germany, Cyprus) generally benchmark wind generation against historical performance or against a reference turbine. Given Vermont's size cap, however, it is recommended that the state pursue a more simplified approach to differentiation based on capacity.

⁴ This incentive is for projects that start construction prior to the end of 2010.

interest of Vermont ratepayers and taxpayers that the FIT encourage the utilization by projects of all Federal incentives by the generators.⁵

- *Should the Board determine generic costs differently for public (non-taxable) entities v. private (taxable) entities?*

REV recommends that the Board determine generic costs differently for non-taxable entities and taxable entities if it is necessary to provide “sufficient incentive for the rapid development and commissioning of plants and does not exceed the amount needed to provide such an incentive.” 30 V.S.A. §8005(b)(2)(B)(III).

Non-taxable entities, such as public sector and non-profit organizations, may be unable to monetize the available Federal and state tax incentives. In this situation, non-taxable entities should receive a FIT rate that is adjusted upward to reflect generation cost without taking tax incentives into account

- *How should the Board value costs of interconnection including system impact studies? Are these costs a barrier to small-scale projects? What share of these costs should the developer pay?*

REV recommends that the Board investigate the costs of interconnection to be allocated to projects, as this could be a substantial barrier-to-entry for small and medium-sized projects. The Board should also consider routing standard offer projects that are under 150 kW through the net metering interconnection and certificate of public good (CPG) process, and consider an option under which there would be a ratio of cost share based on the size of the plant.

- *How should end of life value be considered in cost calculation? Should projects become ratepayer property when a standard offer contract expires?*

REV recommends that generation facilities not become ratepayer property at the end of the standard offer contract. Generators should maintain ownership of their generating assets after the contract expires. This is consistent not only with international FIT best practices, but also with earlier standard offer contracts in the US (e.g. PURPA).⁶ Because it is assumed that generators will maintain ownership of their generating facilities, the end of life value of the systems should not be taken into account in the generation cost calculation. A separate issue that will need to be explored in greater detail is the disposition of renewable energy credits⁷ after the term of the standard offer contract.

⁵ This includes the 30% cash grant that is currently available to taxable entities from the US Department of Treasury in lieu of the 30% investment tax credit. Note, the cash grant program is available to projects that start construction by the end of 2010.

⁶ Grace, R., Rickerson, W., Corfee, K., Porter, K., Cleijne, H. (2009). California feed-in tariff design and policy options. (CEC-300-2008-009F). Sacramento, CA: California Energy Commission.

⁷ For non-agricultural methane generation facilities.

- *Should property tax implications for the installation of renewable systems and income tax implications for sale of output be addressed in the cost calculus?*

REV recommends that the standard offer price should comprehensively include all costs of generation over the lifetime of the system, including income tax implications for the sale of output and any property tax implications for the installation of renewable systems.

- *The statute permits farm methane projects to retain ownership of RECs, while other plants must relinquish RECs to the electric utilities that buy plant power. Should the value of RECs be included in determining the price for farm methane power?*

REV recommends that the value of RECs should not be included in determining the price of farm methane power. The statute expressly provides that the RECs from “methane from agriculture operations. . . shall be retained” by the plant owner. 30 V.S.A. 8005((b)(6)(2009). And the statute also expressly provides that RECs not be included in consideration of incentives available. Furthermore, there are logistical reasons for not including the RECs.

- *What process should the Board employ to determine costs? Should it hire a contractor? How should it obtain input from stakeholders?*

REV recommends that the Board pursue a course that maintains the open, transparent non-contested process now underway, instead of opening a contested legal docket. REV would support the Board’s decision to hire a contractor to assist with data development and analysis, given the firm selected has the required expertise in renewable energy generation and policy structures. There are a number of models for how to determine costs that can be employed that rely on varying degrees of stakeholder engagement and market information.⁸ These could include hiring consultants to conduct research, creating technology working groups, benchmarking against competitive solicitation data, providing an open source pro forma to solicit stakeholder comments on assumptions, etc., or some combination thereof. REV could support a range of these options, provided that the chosen option leads to a streamlined, transparent, and accurate approach to cost setting. REV also believes that it is critically important to include members of the investment and financing community in any stakeholder engagement process.

2. Return on Equity Issues

- *What costs should be considered “equity” for purposes of determining rate of return?*

⁸ See e.g. Grace et al. (2009), p. 70-71.

REV recommends that all costs contributed by the equity participants in a project, from start of development to commercial operations, be considered equity.

3. Adjustment Factor

- *How should the Board determine that prices are high enough to provide sufficient but not excessive incentive?*

REV recommends that the Board monitor market response to the standard offer, trends in the technology and financial markets, and stakeholder feedback. The Board should monitor response to the standard offer program by tracking type and volume of resource in the queue. The need for an adjustment might be signaled if there is not rapid development and commissioning of a specific technology or plant size. The Board will also need to remain apprised of changes in key market indicators over time, such as significant changes in equipment and financing costs or incentives. Feedback from the financial and investment community would also be useful.⁹ The statute seems to give the Board authority to make adjustments, after the public has a chance to review and comment, to the prices at any time based on their own analysis. It is important to note that the price adjustment process needs to be predictable (in terms of timing) and transparent in order to minimize perceived policy instability and maximize participation.

- *Should the Board consider setting prices through an auction mechanism?*

REV recommends that an auction not be utilized to set prices. To date, an auction mechanism has not successfully been utilized for FIT price setting, and most jurisdictions (e.g. Gainesville, FL, and Ontario, Canada) set their prices administratively, using varying degrees of stakeholder input. In the US, auctions were considered for the New Jersey solar energy market transition,¹⁰ for example, as a means to set fixed-price, standard contracts,¹¹ but the auctions were ultimately not selected by the Board of Public Utilities because of their complexity and administrative cost.

- *Should any "adjustment factor" incorporate an incentive for peak production or location in a constrained area?*

⁹ See e.g. Scotia Capital's analysis of the new Ontario feed-in tariff. Scotia Capital (2009). *Alternative & Renewable Energy Crunching the Numbers on Ontario's Proposed Feed-In Tariff Program*. Available online from:

[http://www.powerauthority.on.ca/fit/Storage/44/10191_Alt___Renewable_Energy_Crunching_the_Numbers_20090421_\(3\).pdf](http://www.powerauthority.on.ca/fit/Storage/44/10191_Alt___Renewable_Energy_Crunching_the_Numbers_20090421_(3).pdf)

¹⁰ O'Brien, C., & Rawlings, L. (2006). A description of an auction-set pricing, standard contract model with 5-year SREC generation. In *White paper series: New Jersey's solar market* (pp. 36-53). Trenton, NJ: New Jersey Clean Energy Program

¹¹ Summit Blue Consulting, & Rocky Mountain Institute. (2007). *An analysis of potential ratepayer impact of alternatives for transitioning the New Jersey solar market from rebates to market-based incentives* (Final Report). Boulder, CO: Summit Blue Consulting. Prepared for the New Jersey Board of Public Utilities, Office of Clean Energy

REV would support value-based multipliers to better capture the societal values that specific projects may contribute, such as peak production or production in a load constrained geographic area. Generally, however, it is REV's position that the standard offer prices, including future adjustments, should be calculated based on the generation costs of each technology, rather than based on calculations of value.¹²

4. Other

- *How, if at all, should outage rates, availability, capacity factor, and generic performance criteria be used in developing prices?*

REV recommends that the Board should work with industry stakeholders to develop technology-specific consensus assumptions that should be built into price models. Generally, there is historical data available for renewable energy systems on typical outage rates, availability, capacity factor, and generic performance criteria which can be used when building the models used to evaluate and set generation cost-based rates in Vermont.

- *Should prices account for any system improvements necessary for interconnection?*

REV recommends that a system of cost sharing for interconnection and system improvements be developed that supports the rapid deployment of renewable resources. The broad question of interconnection cost allocation deserves further investigation. As discussed above, the cost of interconnecting to the grid should generally be borne by the generator, as long as the cost does not serve as a significant barrier to development. System improvements (including both distribution and transmission system upgrades) are highly location-specific, and it can be administratively difficult to set a feed-in tariff rate that could adequately reflect different system upgrade costs for a range of sites and technologies. This difficulty suggests that costs associated with transmission and distribution (T&D) upgrades should be removed from the price and socialized through a separate mechanism. In some feed-in tariff jurisdictions,¹³ for example, the entire costs of T&D upgrades are borne by the ratepayers, while in other jurisdictions there is some degree of cost sharing by the generator.

¹² For a more thorough discussion of the pros and cons of cost-based and value-based approaches to feed-in tariff rate setting in the US, see Grace et al. (2009) and Grace, R., Rickerson, W., Porter, K., DeCesaro, J., Corfee, K., Wingate, M., & Lesser, J. (2008). Exploring feed-in tariffs for California: Feed-in tariff design and implementation issues and options (CEC-300-2008-003-F). Sacramento, CA: California Energy Commission

¹³ E.g. see Klein, A., Held, A., Ragwitz, M., Resch, G., & Faber, T. (2007). *Evaluation of different feed-in tariff design options: Best practice paper for the International Feed-in Cooperation*. Karlsruhe, Germany and Laxenburg, Austria: Fraunhofer Institut für Systemtechnik und Innovationsforschung and Vienna University of Technology Energy Economics Group

- *How should issues relating to capital structure and financing be addressed in developing pricing information?*

REV recommends that it is simplest to assume an all-equity structure. Given that capital structures may vary widely, especially for the range of project sizes possible under this program, it would be consistent to set the return on equity at a corresponding all-equity rate.

- *How should the Board set prices for new technologies that develop in the future?*

REV recommends that prices for new technologies be set using the same method used to set prices for existing technologies. In setting prices for new technologies, the Board could consider a collaborative, non-adversarial process that builds on the Board's existing statutory authority. The Board may "add technologies or technology categories to the definition of "renewable energy . . ." 30 V.S.A. §8002(2)(D). Prices can be set, if appropriate, during the same docket.

A. Determination of Project Eligibility

1. General

- *Is there a need for rules defining eligibility? Should they vary by technology?*

REV recommends that no further rules defining eligibility be developed, with the exception that no person¹⁴ can have more than 4.4 MW of capacity in the queue at a time. The rules for eligible technologies, project sizes, and in the case of biomass, generating facility efficiency, are clearly established in the statute. No additional technology-specific eligibility rules need to be established at this time. REV would suggest that no person or business (including any affiliated people or businesses) can have more than 4.4 MW of capacity in the project queue at any time.

- *Should shares be reserved for small projects or for particular types of projects?*

REV believes that reservations may not be critical to policy success. However, if the Board does decide to investigate reservations for certain technologies or sizes, any such reservation should be one that doesn't require a rule change or lengthy process to revise or eliminate it.

¹⁴ The Board should consider the appropriate scope of the definition of the term "person" in this context. See 10 V.S.A. §6001(14)(A). Specifically, 10 V.S.A. §6001(14)(A)(iii) includes "affiliated" entities as a "person."

- *Should there be a minimum eligible project size? Do residential systems qualify?*

REV recommends that there should be no minimum eligible project size, nor should residential systems be barred from feed-in tariff eligibility. The price levels, and the extent to which the feed-in tariffs are differentiated by capacity within each technology, will ultimately determine which project sizes and which ownership structures can successfully participate. No artificial boundaries related to project size and ownership are therefore necessary.

- *Does a sub-2.2 MW project that takes a standard offer become ineligible if it later expands to more than 2.2 MW?*

REV recommends that a sub-2.2 MW project that takes a standard offer would maintain its contract, but any additional capacity over 2.2 MW would not be eligible for the terms of the Standard Offer.

- *Prospectively, what is the relationship between the Standard Offer, SPEED and net-metering programs?*

REV recommends that generating facilities should be allowed to choose between the Standard Offer and the net metering tariff, if they are eligible for both. The two programs should not be additive, and it is not the intent of the legislation that the Standard Offer would replace net metering. If a generator meets the eligibility criteria for the Standard Offer, but has already signed up for the net metering tariff, they should be permitted to switch from net metering to the standard offer.

2. Trigger and Eligibility Date

- *The eligibility date for non-utility-owned plants is unclear in the statute. What should it be?*

REV recommends that all plants commissioned on or after May 28th, 2009 should be eligible.

- *Are existing facilities, e.g. net metering projects, eligible?*

REV recommends that all plants commissioned on or after May 28th, 2009 should be eligible, as this is the day after the bill (H.446) became law. This should including any project commissioned after May 27th that chooses to net meter – they can still apply for a standard offer contract in the future if they choose.

- *Are existing projects that refurbish or expand production eligible?*

REV recommends that refurbished projects or projects that expand production should be eligible if they meet the definition of “commissioned” in the statute: “if the costs of

modernization are at least 50 percent of the costs that would be required to build a new plant including all buildings and structures technically required for the new plant's operation".

- *Are projects put in service between now and when interim rates are set in September eligible? Should there be a separate queue for these Projects?*

REV recommends that projects commissioned between May 28th and when interim rates are set in September should be eligible for the feed-in tariff. There should not be a separate queue for these projects because it is expected that the queue will not open before October 1st.

A. Queuing Process

- *How can the Board prevent hoarding while avoiding excessive barriers to entry? Require posting of security? Require milestones in Project development?*

REV recommends that the Board consider a security deposit and milestone requirements that do not penalize a developer for permitting delays beyond their control. In addition, as mentioned above, the Board should consider setting a limitation of 4.4 MW that any person can have in queue at a given time. The presence of a cap for the Vermont feed-in tariff will create an incentive for speculative queuing behavior among developers. In order to decrease the risk of speculative queuing, it is proposed that developers be required to submit a refundable security deposit, differentiated by project size,¹⁵ that is refunded when the project begins operation. Other measures, such as demonstration of site control, may also need to be considered.

Once enough standard offer applications have been filed to meet or exceed the overall cap of 50MW, applications should continue to be accepted and placed on a waiting list, in order to take into account the fact that some generation facilities may fail to meet milestones or may withdraw from the queue.

- *How long should a developer be permitted to hold a spot in the queue?*

Generators should forfeit their spot in the queue if the customer has not commenced operation or executed an interconnection agreement within a specific period of months. The Board should explore whether the allowable time in the queue should be differentiated by technology and by project size, such that smaller systems with quicker lead times would be permitted a shorter base period in the queue. The feed-in tariff authorization could be extended by an additional period of time for generation facilities

¹⁵ With the option that small projects, such as those 15 kW and under, not be required to pay a security deposit.

that have executed interconnection agreements. Thereafter, a generation facility could have the option of purchasing queue extensions, again differentiated by project size.¹⁶

- *Is there a need for two queues – one for rate and one for interconnection?*

REV recommends that there should only be one queue for the standard offer price.

- *Who should manage the queue?*

REV recommends that the queue be managed by a central authority, such as the SPEED Facilitator. The central authority would also be responsible for monitoring progress towards the cap, and managing the waiting list.

B. Standard Offer Contract Terms

1. REC Issues

- *The statute provides that the RECs associated with a plant that accepts a standard offer are owned by the retail electric providers purchasing power from the plant. Should the standard offer contract require the plant owner to apply for RECs? If so, for resale into what market?*

REV recommends that the standard offer contract not require the plant owner to apply for renewable energy credits. It is assumed that the SPEED facilitator will play an REC aggregation and sale management role, and will apply for RECs based on prevailing regional market conditions.

- *Should the producers have affirmative obligations to work with the utilities to assist in the sale and retirement of RECs?*

REV recommends that producers have affirmative obligations to work with the utilities to assist in the sale and retirement of RECs. This means that the producers should work with the SPEED facilitator to complete the paperwork, comply with monitoring and verification protocols, etc., to ensure that RECs can be sold. As discussed above, however, it is assumed that the SPEED facilitator will be responsible for the actual sale of the RECs into specific markets.

- *Is it necessary to create a mechanism to ensure that RECs are not claimed by more than one party?*

¹⁶ These queuing procedures have been benchmarked against other policies such as the feed-in tariff proposed by the Hawaii Electric Company (KEMA, Inc. (2008). *HECO Feed-In Tariff Program Plan*. Prepared for Hawaiian Electric Company, Inc., Maui Electric Company, Limited, and Hawaii Electric Light Company, Inc.) and the net metering enrollment procedure employed by the State of Illinois, available online at: <http://www.ilga.gov/commission/jcar/admincode/083/083004650000350R.html>

REV recommends that a mechanism should be utilized to ensure that RECs are not claimed by more than one party. It is assumed that producers will be responsible for enrolling in the NEPOOL GIS tracking system and that this will provide a check against double counting of generation attributes, so it does not appear necessary to create a dedicated tracking mechanism for Vermont.

2. Contract Term

- *The statute specifies that the standard offer contract term shall be 10-20 years for all plants except solar plants. For solar plants, the term is 10-25 years. Who should decide on the specific duration of a contract? Should feed-in tariff rates be permitted to adjust over the course of the contract, and if so, how?*

REV recommends that developers have options as to the terms, within the parameters of the statute (10 to 20 years except 10 to 25 years for solar).

Another issue for the Board to consider with regard to contract term is whether the price provided to the generators adjusts for inflation over time, such that once a generator locks into a 20 year price, that price could change if pegged to an indicator such as the Consumer Price Index. The National Regulatory Research Institute recently concluded that inflation adjustments for generators that have fixed fuel costs may not be necessary, since operations and maintenance costs over time are minimal.¹⁷ An inflation adjustment should be considered for generators that have significant exposure to fuel price risk over time, such as biomass generators.

Thank you for considering these comments. We look forward to participating in this docket.

Sincerely,



Andrew Perchlik

¹⁷ Boonin, D. Feed-in Tariffs and Hawaii's Clean Energy Initiative. Silver Spring, MD: National Regulatory Research Initiative. Prepared for the Hawaii Public Services Commission.

Appendix A
Comparison of Feed-in-Tariff Pricing Structures

Energy Type	Germany	Michigan	Ontario	Spain
	Threshold	Threshold	Threshold	Threshold
Hydro	<500 kW	<500 kW	< 50 MW	< 10 MW
	500 kW to 2MW	500 kW to 10 MW		10 MW to 50 MW
	2 MW to 5 MW	10 MW to 20 MW		
Wind	Threshold	Threshold	Threshold	Threshold
	Differentiated by wind resource.	Differentiated by turbine output.	Differentiated by onshore, offshore or by ownership structure.	Differentiated by onshore or offshore.
Biomass / Biogas	Threshold	Threshold	Threshold	Threshold
	<i>Biomass</i>	<i>Liquid / Gas Only</i>	<i>Biomass</i>	<i>Energy Crops</i>
	< 150 kW	< 150 kW	No threshold.	< 2 MW
	150 kW to 500 kW	150 kW to 500 kW		
	500 kW to 5 MW	500 kW to 5 MW	<i>Biogas</i>	
	5 MW to 20 MW	5 MW to 20MW	<5 MW	> 2 MW
			> 5MW	
Landfill Gas	Threshold	Threshold	Threshold	Threshold
	<500 kW	< 500 kW	<5 MW	No threshold.
	500 kW to 5 MW	> 500 kW	> 5MW	
		(also applies to sewage gas)		
Photovoltaic	Threshold	Threshold	Threshold	Threshold
	<30 kW Rooftop	<30 kW Facade Cladding	< 10 kW Rooftop	< 20 kW
	30 kW to 100 kW Rooftop	30 kW to 100 kW Facade Cladding	10 kW to 100 kW Rooftop	
	>100 kW Rooftop	> 100 kW Facade Cladding	100 kW to 500 kW Rooftop	
	>1000 kW Rooftop	< 30 kW Rooftop	< 10 MW Ground Mount	<200 kW
		30 kW to 100 kW Rooftop		
		> 100 kW Rooftop		
				>200 MW